COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS & ENERGY

Investigation by the Department on its own Motion into Distributed Generation	)	DTE No. 02-38

<u>REPLY COMMENTS OF REALENERGY, THE JOINT SUPPORTERS, HESS MICROGEN, THE E CUBED COMPANY, LLC, NUVERA FUEL CELLS, NORTH BATTERY DEVELOPMENT LLC AND BERKSHIRE DEVELOPMENT LLC</u>

RealEnergy, Inc. ("RealEnergy"), The Joint Supporters[1], Hess Microgen, the E Cubed Company LLC, Nuvera Fuel Cells, North Battery Development LLC and Berkshire Development, LLC offer the following comments in reply to the various comments submitted to the DTE in the above-captioned investigation.

1. <u>Introduction</u>. RealEnergy, the Joint Supporters and the other signatories to these reply comments are encouraged by the level of consensus in the comments submitted to the Department. Nearly all of the parties responding to the Department's Investigation recognize the potential for distributed generation ("DG") to play an increasingly important role in the Massachusetts energy sector. We strongly support the Department's efforts to encourage the development of DG in Massachusetts in the short term and to shape the long-term competitive landscape for DG.

2. <u>Interconnection Standards</u>. We first re-iterate our initial comments regarding interconnection standards, and echo the comments of other responding parties as well: the Department should establish a collaborative process to develop uniform

interconnection standards for Massachusetts.[2] A Massachusetts Interconnection Collaborative should include: the distribution companies, DG developers, equipment suppliers, end users, policymakers and other interested parties. We note that collaborative efforts in other states like California have proven successful, leading to the adoption of interconnection standards that accommodate the interests of all stakeholders. We appreciate the generous offer of the Massachusetts Technology Collaborative ("MTC") to assist in the funding and facilitation of the Massachusetts Interconnection Collaborative and we support the MTC's efforts.[3]

We urge the Department to resist any call by the distribution companies to allow them to engage in an exclusive, isolated process to develop interconnection standards without the involvement of the Department or other important stakeholders (e.g. the actual DG providers themselves). The distribution companies began working together earlier this year to develop uniform interconnection standards for different classes of DG.[4] While we await with interest the first set of standards for systems of 10 kW or less (which are relevant to residential and very small commercial applications only), our experience suggests that distribution companies often have a limited working knowledge of DG systems and operations. Further, we have seen distribution company engineers

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[1] The Joint Supporters (for purposes of these comments) are the Distributed Power Coalition of America; IEC Engineering, P.C.; Siemens Building Technologies; Harbec Plastics, Inc.; and RealEnergy, Inc. Their representative is The E Cubed Company, LLC.

[2] Several parties advocated a collaborative process for the development of uniform interconnection standards. See Comments by RealEnergy, p. 8; MTC, p. 5, 22; Stone & Webber Consultants, p. 2; Western Massachusetts Electric Company ("WMECo"), p. 4; Ingersoll-Rand ("Ingersoll"), p. 3.

[3] See comments of MTC, p. 5, 22.

[4] See Comments of Massachusetts Electric Company and Nantucket Electric Company ("MECo"), p. 5; NSTAR Electric Company ("NSTAR"), p. 32.

require small DG systems to meet standards that large central station power plants must meet, and that the distribution company's own equipment often cannot meet.

The distribution companies' effort represents a positive recognition that uniform interconnection standards will benefit everyone. However, we are concerned that a unilateral effort by the distribution companies will not properly balance the competing interests when dealing with issues pertaining to equipment size, export verses non-export, different technology types, and other matters, particularly as the technical challenges raised by more complex systems are addressed.

We note that in their responses to the Department's queries in the Order of Investigation for this proceeding, the distribution companies who filed comments either deny that their current interconnection procedures present barriers to DG,[5] or ignore the Department's questions altogether.[6] Other comments from the distribution companies were inaccurate or misleading. For example, several points and concerns raised in NSTAR's comments on interconnection are a stale rehash of anachronistic "issues" that have been considered and resolved by distribution companies elsewhere in the country.[7] NSTAR's comments are also somewhat confusing at times, making issues seem more

[5] See MECo, p. 2-4; WMECo, p. 1.

[6] NSTAR, 31-32. Given that NSTAR's interconnection procedures expressly prohibit interconnection in the Boston network system, it is not surprising that NSTAR fails to address the question presented by the Department. NSTAR representatives recently reaffirmed this express barrier to interconnection. We submit NSTAR'S approach to these issues does not engender confidence that left to its own devices, NSTAR will adopt reasonable and effective interconnection standards.

[7] For example, on page 15 of its comments, NSTAR asserts that relatively small amounts of DG will not have an impact on market prices. This assertion has been refuted in New York in a study completed to assess the likely impact on the market of the NYISO's demand response programs (NYISO PRL Program Evaluation: Executive Summary). Likewise, on page 16, NSTAR asserts that one of the most important issues regarding the safety of DG is the need to protect against "islanding." This is a well-worn concern that other distribution companies have easily addressed with protective equipment. Moreover, we suspect that NSTAR is quite comfortable selling energy to customers running large synchronous motors, which are equally capable of sending short-circuit current out into the system.

complex than they actually are.[8] The conclusion reached by NSTAR is that the Department should stand idly by while the distribution companies work together to design uniform interconnection standards.[9] We note, however, that both WMECo and Fitchburg Gas & Electric are open to a collaborative process.[10]

In contrast, others were nearly unanimous in the conclusion that current interconnection standards and procedures do, in fact, present a barrier to DG.[11] This disconnect between the perspective of the distribution companies -- that there is no problem -- and the views of nearly all other respondents highlights the need for a collaborative process involving all stakeholders. In short, we think that the process would benefit from the perspectives and experience of DG providers, equipment suppliers and end users. The process would also benefit from the perspective of policymakers and other interested third parties that support the development of DG.

That said, nearly all responders, including the distribution companies, conclude that properly structured uniform interconnection standards would facilitate and accelerate

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[8] For example, on page 8 of its comments, NSTAR asserts that different levels of safety apply to different technologies. While this is true, the differences are not great, and the issues are not particularly complex. RealEnergy has handled safety issues without problem in radial and network system environments. Likewise, on page 9, NSTAR asserts that because synchronous generators are self-determined and are not a function of the voltage and energy supply level requirements of the grid, they have the potential to cause extensive damage if they are connected to the grid without being "synchronized" to the system. This statement is simply wrong for units under 2000 kWs. It is not possible for relatively small units (compared to load on the circuit) to set the voltage. Instead, the grid voltage would overpower such units and determine the system voltage at the point of interconnection. Only large units, such as utility power plants (100+ MWs), are ever likely to "set" the voltage on the grid.

[9] NSTAR, p. 32.

[10] WMECo p.4, Fitchburg Gas & Electric ("FGE") p. 2

[11] Ingersoll, p. 1; National Association of Energy Service Companies "NAESCO"), p. 2; Gas Technology Institute ("GTI"), p. 1; Cape Light Compact ("CLC"), p. 3; FGE, p. 3; Solar Energy Business Association of New England ("SEBANE"), p. 4; MTC, p. 15; AES New Energy, p. 2; Boston Gas Company, et al. ("BGC"), p. 2; RealEnergy, p. 3; Northeast CHP Initiative, p. 3; Stone & Webster Consultants, p. 12; Capstone Turbine Corporation, p. 2.

the development of DG in Massachusetts.[12] The question thus is not if, but rather who, how and when Massachusetts should adopt uniform interconnection standards. To be sure, there is a broad spectrum of opinion regarding the appropriate structure for the interconnection standards. There are many technical issues to consider and resolve. That is why a collaborative approach makes sense.

There is also agreement among nearly all of the parties that system safety and reliability are paramount concerns. Current methods and procedures for addressing system safety and reliability concerns must be tested and measured against new technologies and methods for ensuring the same.

We therefore again strongly urge the Department to convene a Massachusetts Interconnection Collaborative to develop uniform, efficient interconnection standards and procedures. (In the interim we urge the Department to consider adopting the California interconnection standards, which themselves were developed in a collaborative process.) By working together, DG stakeholders can resolve mutual or unilateral misunderstandings, test underlying assumptions, and reach a fair result. Massachusetts will then have interconnection standards that draw on the experiences of all stakeholders, as well as best practices from other states. This process worked, and is working, in California.

We offer the following ideas with respect to establishing uniform interconnection procedures:

?? DG companies, customer groups and other non-utility interested parties have very limited resources to participate in the regulatory process. A sure path to failure in the collaborative workshop process is to have too many meetings over an extended period of time. That is why it is important to build on the

[12] MECo, p. 3-4 , NSTAR p. 17, 20; WMECo, p. 2; FGE, p. 3; Ingersoll, p. 1; United Technologies Corporation, p. 3; GTI, p. 1; CLC, p. 3; Meadwestvaco Corporation ("Meadwestvaco"), p. 3; MTC, p. 5.

lessons learned from other jurisdictions. With that said, we recommend the Department allow the collaborative process to proceed with a limited number of separate working groups.

?? The first order of business should be an all-hands meeting to establish the procedures and protocols that will guide the collaborative. A *strong* non-interested facilitator is critical to success. The process should be divided into two main areas: non-technical contractual interconnection issues and technical issues. Within these areas the following working groups are recommended. Each area/group should have a strong facilitator responsible for driving the process.

    ?? Group 1 should be established to consider issues that apply to systems that will not export power to the grid. Grid safety and reliability concerns are minimized and interconnection procedures (particularly impact studies) can be streamlined and simplified if the DG system in question is designed with adequate reverse power relays or other devices to prevent power from flowing back to the grid.

    ?? Group 2 should be established to consider issues related to system size, both absolute and relative to grid capacity. We suggest the following groupings:

    0 kW < DG System < 20 kW

    20 kW < DG System < 250 kW

    250 kW < DG System < 2 MW

    2 MW < DG System

    Group 2 may well determine that the interconnection standards for systems less than 10 kW currently under development by the distribution companies are perfectly acceptable. If that is the case, after a brief vetting process, those standards may be suitable for release and adoption. In fact, consideration of those standards might make an excellent first step for the proposed Massachusetts Interconnection Collaborative. But it must not be the only step: New York, for example, has yet to move beyond its initial effort.

    ?? Group 3 could consider different generator types: synchronous, induction or inverter based. This group would clearly coordinate activities with the other two groups.

The Department should avoid a one-size-fits-all interconnection standard, as is the goal of IEEE p-1547. While some general terms would be appropriate, interconnection requirements vary depending on the size and types of systems involved. The goal should be to minimize the costs of interconnection for any given type of DG system while maintaining adequate margins for safety and protection. The parties that present these comments have interconnected our DG systems with a range of distribution systems, including network systems. They have participated in collaborative interconnection processes in several other states. They would like to bring the benefit of these experiences to a Massachusetts Interconnection Collaborative.

3. Electricity Rates for Customers Employing Distributed Generation. In response to the Department's inquiry, the distribution companies offer several well-worn arguments to support the imposition of so-called standby tariffs.[13] While we can (and will) argue the substance of the complex issues involved in determining appropriate standby rates, the most important point is that many of the arguments advanced by the distribution companies simply do not apply to smaller-scale DG as it stands in the market today or likely will in the near future.

Excluding large-scale cogeneration applications, DG systems simply will not have a discernible impact on system planning, revenue forecasting and similar concerns over the next several years. The cost of providing back-up service to a customer with two 200 kW DG systems is arguably negative. The capacity actually needed to service such a system is well within the parameters of normal system variation. In fact, one can argue that DG will have a net positive impact, as it will add "unplanned" capacity to the system,

[13] RealEnergy views the term "standby" as a misnomer, because it inaccurately implies capacity idly standing-by and dedicated to serving the back-up supply needs of a DG customer. RealEnergy has never seen a truck with two linemen idling in the parking lot with a generator and transformer in the back waiting to plug in when a DG system breaks. In fact, distribution company assets are nearly always in use, except in very limited circumstances.

and the other users and distribution companies will derive system benefits and revenues from that additional capacity.

The Department should address the myriad issues regarding appropriate cost recovery and rate design for customers that choose to utilize DG only when a critical mass of DG market penetration is reached. Now is not the time for a costly and contentious so-called “standby” rate case that is geared to deal with the (likely distant) future situation when DG forms a substantial part of the Massachusetts electric market. Such a rate proceeding is premature at this point and could well lead to additional barriers to DG. If nothing else, the resulting uncertainty is sure to have a dampening effect on DG activity.

Nevertheless, we urge the Department to focus now on existing rate structures and take steps to limit the negative impact on DG. We suggest the Department adopt a simple interim rate for customers utilizing DG that provides transmission and distribution service for supplemental, back-up and maintenance power. The current MECo rates could form a common starting point. As will be shown below, the key is to reduce dependence on high, fixed demand charges.

As noted by several respondents, standby rates are not prevalent in Massachusetts. Except for Cambridge Electric, no other distribution company has a standby rate applicable to new generation. Currently, customers with DG are served on a non-discriminatory basis under the otherwise applicable rate regime.[14] While existing general rates for distribution service may not explicitly discriminate against DG customers, they

[14] MECo p. 6.

still present a significant barrier to DG (and other demand management measures such as real-time metering, load shedding, and storage)[15] in practice.

High fixed demand or capacity charges based on potential demand, contract capacity or even maximum monthly demand, rather than actual usage, can cripple the economics of a DG project. This holds true whether the rates are targeted or generally applicable. The key variable is the extent to which such rates are weighted toward fixed fees based on the demand or capacity potentially required by the DG customer. For example, Boston Edison has a distribution service rate (Rate T-2/B-2) that is based primarily on maximum incremental peak demand during a monthly period.[16] If a customer with 1 MW of load served by DG must shut down its system for one hour during the middle of one day in September, the customer would face a fixed demand charge of $23,000 for the month and a variable charge of $2,512. This outcome could well render the DG project economically unfeasible.[17]

A more fair and reasonable allocation of costs for electric service would place a greater emphasis on a DG system's demand on system capacity. The Department should take great care in assessing the practical impact that rate design will have on DG, and design demand-management tariffs, including tariffs for customers that utilize DG, in a way that allows fair cost recovery but does not stifle DG.

[15] Typically, demand charges account for 40% to 60% of a customer's monthly bill. Demand charges are often based on the peak usage recorded within any 15 or 30 minute period during the month. Thus, a customer can demonstrate positive demand management behavior for 99.5% of the month and lose the entire economic benefit but due to one small excursion.

[16] Boston Edison Company Tariff M.D.T.E. No. 940, Rate T-2.

[17] See also Exhibits A and B from the comments of Wyeth Biopharma for a summary of applicable demand charges from existing rates.

A simple analogy to a toll road makes this point clear. One who drives on the road every day should pay more for the use of the road than someone who drives on the road once a month. It is arguably fairer to charge the intermittent user a higher toll when he uses the road, but it is not reasonable to charge him an excessive "user" fee for the mere privilege of possibly using the road, particularly if he actually uses the road much less than others. A high capacity charge creates a windfall for the toll operator or an inappropriate cross subsidy for the heavy users. The analogy quickly gets complex as one mixes and matches variable usage tolls and fixed charges, but the principles remain. One point that bears mentioning is that, unlike a car that intermittently uses a toll road, a DG system actually <u>provides</u> capacity, in effect adding an additional lane during the "rush hour" when the DG system is operating. The DG system provides this "lane" at no cost to the other drivers or the toll road operator. In spite of this benefit, the distribution companies (the "toll road operator" in this hypothetical) not only fail to recognize the benefit, they often want to charge the distributed generator an additional charge above and beyond what other users pay.

The distribution companies argue that in order to plan and provide standby service to DG customers, the costs are identical to, if not greater than, the costs of providing similar distribution capacity to a regular customer who uses the system every day, and that distribution capacity payments should be based either on (1) the maximum potential capacity that the customer may require from the system (also often referred to as "contractual demand"), assuming, unrealistically, that such requirements would occur across all DG users at the coincident peak system capacity,[18] or (2) the total amount of energy consumed by a customer in a given month, inclusive of any DG.[19]

We reject these arguments, and strongly disagree with NSTAR and WMECo that standby service for transmission and distribution should be based on contractual demand. WMECo offers no real support for its argument, and NSTAR's arguments are flawed in several respects. As NSTAR aptly points out, the Department has rejected fees based on contractual demand in its most recent standby case.[20] Furthermore, we believe that NSTAR has misinterpreted and misapplied the findings in the other precedent it relies on – a recent New York standby rate case.[21]

We agree that a small component of costs for electric service are truly fixed, and hence appropriate to be recovered under a fixed capacity or demand (i.e. $/kW) type of charge. However, this is a small proportion of the overall costs, and relates to equipment and services provided that are "close to the customer." The majority of costs associated with the provision of electric service are more appropriately considered shared costs and more fairly allocated on a usage basis (i.e. $/kWh).

This was exactly the reasoning underlying the decision in the New York Order referenced by NSTAR. The NY Public Service Commission ("NYPSC") found that contractual demand was appropriate to recover costs that were located close to the customer – i.e. customer specific. The farther you get from the customer, however, the

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[18] NSTAR, p. 11, WMECo p. 6-7.

[19] MECo p. 14-15.

[20] See NSTAR p.26, citing Cambridge Electric Light Company 94-101/95-36.

[21] Opinion and Order Approving Guidelines for Design of Standby Service Rates, 99-E-1470 (Opinion 01-4) (the "New York Order").

more remote the nexus between customer and cost becomes and the more the costs associated with providing standby service should be considered "shared" with other system users. The NYPSC further found that "shared" costs are appropriately charged on a daily demand (i.e. usage or kWh) basis, including all transmission costs.[22]

In its comments, NSTAR argues that standby rates should be based largely on contractual capacity demand. NSTAR relies on the reasoning of the NYPSC to support contractual demand payments, but then fails to dis-aggregate or distinguish "shared" costs (like transmission service). Instead, NSTAR lumps those costs without justification. While we can argue about the extent to which certain capacity costs related to <u>distribution</u> service belong as part of a fixed charge, NSTAR recommends that the standby rates be based on contractual demand only, and includes <u>transmission</u> costs associated with standby service as part of the contractual demand. In short, we think the arguments for a standby rate based on contractual capacity demand are not well founded and have been stretched well beyond the principles and reasoning of the cases used to support them.

The conclusion we draw from reviewing the comments in this Investigation is that a long and contentious proceeding to establish standby service rates is premature. The simple argument that "we had to build for 100% of your potential capacity, so you have to pay for it whether you use it or not" is not convincing. Moreover, there is not enough DG in place today to assess the true costs and benefits of DG accurately. The better approach is to establish a temporary DG Service rate regime that recognizes costs everyone can reasonably agree upon, but that forestalls final resolution of more complex

[22] Id.

and contentious points until more relevant data are developed. Now is not the time to impose additional burdensome standby rates on DG.

To the extent such a rate structure would encourage the development of DG, we would say that is exactly the point. At the end of the interim period, the Department would likely have a body of useful data from which to measure the costs and benefits of DG. To the extent that the distribution companies could demonstrate that they incurred costs greater than the value of the benefits derived, then they would have firm ground for a rate case.

Despite areas of strong disagreement, there is a general consensus among distribution companies and others that if the Department should decide to establish specific DG Service rates in the future, such rates should accurately reflect the costs of providing such service, as well as the benefits that the DG system may impart to the distribution system.[23] There is also a general consensus that the costs of providing service to supplement or back-up the DG system will vary dependent upon the load served, its location on the distribution system, and the timing of the requirement for standby service. Alternative service rates, which capture the cost of these variables, are discussed at length in the initial comments of several responders, including the distribution companies.[24]

The variable aspect of the costs and benefits of electric service for DG customers is perhaps the most important issue to be resolved.[25] We agree that such electric service

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[23] NSTAR, p. 18; WMECo, p. 5; MECo, p. 8; RealEnergy, p. 13; AES, p. 3

[24] AES, p. 7, 9; WMECo, p. 6; MECo, p. 10, 15-16.

[25] AES, p. 4; NSTAR, p. 18; Ingersoll, p. 5; United Technologies Corporation, p. 4; Northeast Energy and Commerce Association, p. 2-3; CLC, p. 4; MECo, p. 8.

rates can and should be structured to recognize the variable nature of the costs incurred. This cost variability has two dimensions. The first dimension relates to the allocation of fixed demand ($/kW) versus variable volumetric ($/kWh) cost recovery. High demand charges create disincentives for DG and any other demand-side measures. The second dimension of the variable nature of costs is that customers should have a choice about the type of service they require, and rates should reflect the costs and benefits of the service options. One point we wish to emphasize is that as an alternative to "interruptible" supply, a customer should be able to obtain service that has limited parameters with a penalty premium price for any service taken outside the parameters of time, congestion, and the like.

On a broader note, we agree in many respects with the comments filed by AES that view distribution rates in totality, and DG as one piece in a larger mosaic.[26] DG that is not exporting power is indistinguishable from any other means of load reduction, and it should be treated as such. There is no basis to discriminate against DG. AES also points out that rates should be more flexible to meet actual customer requirements and that usage based rates more accurately capture value and are more efficient. With advances in technology and information management, rate design can be much more precise. Finally, AES makes the point that revenue recovery is not guaranteed and is not a stranded cost issue. The Department should heavily weigh AES's comments regarding distribution rates in light of the fact that as a competitive supplier of grid-delivered electricity, AES has no direct vested interest regarding DG.

[26] Comments of AES, p. 5.

4. Distribution Company Ownership of Distributed Generation. Ownership of DG by regulated monopoly distribution companies is not a good idea. One fundamental tenet of electricity restructuring was that distribution companies were to get out of the generation business. The distribution companies should focus on what they do best, running wires. Allowing distribution companies to own DG, even for the limited purpose of system stability or upgrade deferment, would likely distort the market.

As the distribution companies acknowledge in their comments, some of the prime opportunities for DG are to be found in the areas where system capacity upgrades are needed. If the past is any indicator, distribution companies would reserve this low hanging fruit for themselves, and competitive DG providers would be at a substantial competitive disadvantage. Rather than allowing distribution companies to own DG, they should be required to go to the market and competitively bid out such opportunities to encourage market competition and development. While we believe the monopoly franchise granted to the distribution company carries with it the obligation to reduce costs (even when that may reduce the monopolist's revenues), the Department may wish to consider allowing the distribution companies to retain a portion of the savings for their ratepayers as an incentive to spur adoption of non-wires alternatives.

5. New England Regional Cooperation on Market Rule Development. Several respondents have referenced the emergence of ISO-New England markets for load response and distributed resources (including demand response, DG and renewables), especially in load pocket situations and elsewhere. These markets will affect and will be affected by some of the market rules under consideration in this proceeding. The Department should foster opportunities and remove barriers for DG

owners and operators that wish to participate in those markets as they emerge. It is worth underscoring the statements referencing the instant proceeding filed by ISO New England, Inc. in D.T.E. 02-40. There the ISO stated:

> In opening its investigation on distributed generation, the Department explained that it has "recognized the importance of distributed generation as a resource option in the restructured electric industry." See D.T.E. 02-38 at 1. The Department also recognized that "distributed generation can meet customers' energy needs [and that i]t also has the potential for load response." Id.
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> ISO agrees with the Department's recognition of the potential that load response can play and believes that load response can assist in providing a healthy competitive marketplace. Because distributed generation is a way for demand to respond to price, ISO respectfully submits that the Department should recognize and consider the relationship between its policies concerning distributed generation, a competitive wholesale marketplace and a competitive retail marketplace.[27]

Demand or Load Response, including distributed generation, is under consideration as part of the Standard Market Design (SMD) Notice of Public Rulemaking (NOPR) that the Federal Energy Regulatory Commission ("FERC") released for comment on July 31, 2002. The NOPR deals with these topics broadly. FERC has recently turned to New England (specifically, the New England Conference of Public Utility Commissioners (NECPUC), the Department, ISO-New England and the New England Demand Response Initiative (NEDRI)) for assistance and guidance developing the details of related Standard Market rules for Demand Resources, including DG, in the interface between wholesale and retail markets. The Department should be cognizant of the parallel proceedings at regional and federal levels so that regulatory policies are integrated and harmonized.

[27] ISO-New England Comment in D.T.E. 02-40, Investigation by the Department of Telecommunications and Energy on its own Motion into the Provision of Default Service, p. 6.

5. Conclusions. In concluding our reply to the comments filed by other parties in this proceeding, we offer the following key ideas:

?? The Department should convene a collaborative process to develop uniform interconnection standards.

?? The Department should consider the implementation of an interim DG service rate, based off the current general service rates of MECo, with a low fixed demand charge component, to facilitate the development of a critical mass of DG in Massachusetts.

?? After a sufficient level of DG has been integrated into the Massachusetts distribution systems, the Department should analyze the costs and benefits of DG to the system, and design DG service rates that accurately capture those costs and benefits.

?? The Department should discourage the distribution companies from owning DG.

?? The Department should coordinate regulatory activity regarding DG with other related proceedings at the state, regional and federal levels.

As we have previously observed, DG presents a fundamental competitive challenge to the distribution companies. In some cases, DG presents the potential to reduce distribution company revenues. The benefits of DG will offset and in some cases outweigh the revenue loss. Nevertheless, so long as DG is perceived as a competitive threat, many distribution companies will not voluntarily incorporate DG into the electric system. To be sure, a few distribution companies recognize the potential benefits of DG, and those distribution companies are working collaboratively to arrive at fair and equitable solutions to the challenges posed by DG. The Department's approach to these issues should accommodate both perspectives.

Ultimately, in a competitive market, some entities will prosper more than others will. Protecting one participant to the detriment of others is fundamentally at odds with the developing competitive electricity market in Massachusetts. While it takes time to transition to a proper functioning market, in the long run, with proper oversight, the competitive threats and opportunities will spur all participants to offer higher-value solutions, products and services to customers. We are confident that DG will become interwoven into the fabric of our electric infrastructure. The Department has a unique opportunity to help fashion the market in a manner that sets an example for the rest of the country.

In the long run, if DG is to flourish, distribution company systems will have to move from a largely one-way energy distribution system to a system comprised of multiple sources of generation that accommodates fluctuating power flows. This transition will take time, present technical challenges, and entail costs. These costs should be apportioned fairly among the beneficiaries, including DG owners, distribution company shareholders, energy consumers and other stakeholders. The fundamental premise underlying DG is that in many applications, DG can provide the least cost, most efficient solution to our energy needs. The benefits of DG to the economy will outweigh the costs of a transition to the new paradigm.

Respectfully submitted,

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